Memorandum

To:	Poonum Agrawal, David Meyer, U.S. Department of Energy	CRA No.	D08554-00
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Subject:	**GE MAPS INPUT ASSUMPTIONS: EASTERN INTERCONNECT**		

This memorandum summarizes salient inputs to the CRA locational price forecasting model (GE MAPS). The model geographic footprint encompasses the US portion of the Eastern Interconnect and the Canadian province of Ontario. The analyses simulate the years 2008 and 2011.

Primary data sources for the CRA GE MAPS model include the NERC MMWG, the General Electric generation and transmission databases for the Eastern Interconnect, various publications by NERC regions and Independent System Operators, FERC submissions by generation and transmission owners, and CRA in-house analysis of plant operations and market data. Major data components are listed below.

1. TRANSMISSION

The CRA model is based on load flow cases provided by the NERC Multiregional Modeling Working Group (MMWG). This analysis uses the MMWG 2005 series load flow cases for the summer of 2007 and the summer of 2010. The load flow cases encompass the entire Eastern Interconnect system, including lines, transformers, phase shifters, and DC ties. The Cross-Sound and Neptune high voltage DC cables are added to these cases. Apart from these DC cables, no transmission upgrades are added apart from those included in the MMWG cases. Monitored constraints originate in the following sources:

- The NERC flowgate book.
- The list of flowgates published by the Midwest ISO on their website.
- A list of flowgates provided by the Southwest Power Pool.
- FERC Form 715 filings, seasonal transmission assessment reports, and studies published by NERC regions and Independent System Operators.
- Regional Transmission Expansion Plan (RTEP) reports published by various ISO.
- The 2004 Intermediate Area Transmission Review published by the New York ISO.
- The CP-10 Working Group report (2004) by the Northeast Power Coordinating Council.
- Contingency analyses performed by General Electric and by CRA.
- Historically binding constraints monitored by CRA.

2. LOAD AND ENERGY

For each load serving entity GE MAPS requires an hourly load shape and an annual forecast of peak load and total energy. Loads for forecast years are scaled based on these parameters. Load shapes are drawn from hourly actual demand for 2002, as published in FERC Form 714 submissions and on the websites of various Independent System Operators (ISOs) and NERC reliability regions. Peak load and annual energy forecasts are taken from the most recent data available in FERC Form 714 submissions (2004) and from forecast reports published by ISOs and NERC regions (2005), including:

- Forecast of Capacity Energy Load and Transmission (CELT), 2005 by the ISO New England.
- 2005 Load and Capacity Data report (Gold Book) published by the NYISO.
- 2005 PJM Load Forecast Report published by PJM.

Ontario data is drawn from the 10-Year Outlook: Ontario Demand Report published by the Independent Electricity Market Operator of Ontario

3. THERMAL UNITS

GE MAPS includes a detailed model of thermal generation, in order to accurately simulate operational characteristics, and project realistic hourly dispatch and prices. Modeled characteristics include unit type, unit fuel type, heat rate values and shape (based on unit technology), summer and winter capacities, fixed and variable non-fuel operation and maintenance costs, startup fuel usage, forced and planned outage rates, minimum up and down times, and quick start and spinning reserve capabilities.

The CRA generation database reflects unit-specific data for each generating unit based on a wide variety of sources. In cases where unit-specific data is not available, representative values based on unit type, fuel, and size are used. Table 1 and Table 2 document these generic assumptions. Note that all costs and prices are shown in real 2005 dollars.

Table 1: Generic Unit Characteristics

Unit Type & Size	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Minimum Downtime (Hrs)	Minimum Uptime (Hrs)	Heat Rate Shape
Combined Cycle	$ 2.50	$ 21.00	8	6	2 Blocks, each 50% at FLHR
Combustion Turbine <100 MW	$ 7.00	$ 15.00	1	1	One block
Combustion Turbine >100 MW	$ 7.00	$ 15.00	1	1	One block
Steam Turbine [coal] >200 MW	$ 1.00	$ 35.00	12	24	4 blocks, 50% @ 106%FLHR, 15% @ 90%, 30% @ 95%, 5% @ 100%
Steam Turbine [coal] <100 MW	$ 3.00	$ 45.00	6	8	
Steam Turbine [coal] <200 MW	$ 3.00	$ 35.00	8	8	
Steam Turbine [gas] >200 MW	$ 3.00	$ 30.00	8	16	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [gas] <100 MW	$ 5.00	$ 34.00	6	10	
Steam Turbine [gas] <200 MW	$ 4.00	$ 30.00	6	10	
Steam Turbine [oil] >200 MW	$ 3.00	$ 30.00	8	16	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [oil] <100 MW	$ 5.00	$ 34.00	6	10	
Steam Turbine [oil] <200 MW	$ 4.00	$ 30.00	6	10	

The primary data source for generation units and characteristics is the NERC Electricity, Supply and Demand (ES&D) 2003 database, which contains unit type, fuel type (primary and secondary), and capacity data for existing units. Heat rate data is drawn from prior ES&D databases where available. For newer plants, heat rates are based on industry averages for the technology of the unit. The NERC Generation Availability Data System (GADS) 2003 database, released January 2005, is the source for forced and planned outage rates, based on plant type, size, and vintage. Fixed and variable operation and maintenance costs are estimates based on plant size, technology, and age. These estimates are supplemented by FERC Form 1 submissions where available. The FOM values include an estimate of $1.50/kW-yr for insurance and 10% of base FOM (before insurance) for capital improvements.

Plants that are known to be cogeneration facilities are either modeled with a low heat rate (6000 Btu/kWh), or set as must-run units in the dispatch, to reflect the fact that steam demand requires operation of the plant even when uneconomical in the electricity market.

Table 2: Generic Unit Characteristics

Unit Type & Size	Quick Start (% of Capacity)	Spinning Reserve (% of Capacity)	Forced Outage Rate (%)	Planned Outage Rate (%)	Typical Outage Length (Days)
Combined Cycle	-	30%	1.81%	7.40%	3
Combustion Turbine <100 MW	100%	90%	2.81%	5.28%	1
Combustion Turbine >100 MW	100%	90%	2.60%	6.94%	1
Steam Turbine [coal] >200 MW	-	10%	3.07%	9.10%	7
Steam Turbine [coal] <100 MW	-	10%	3.78%	8.32%	3
Steam Turbine [coal] <200 MW	-	10%	4.57%	9.43%	3
Steam Turbine [gas] >200 MW	-	10%	3.50%	14.11%	7
Steam Turbine [gas] <100 MW	-	10%	2.62%	6.81%	2
Steam Turbine [gas] <200 MW	-	10%	3.23%	11.11%	2
Steam Turbine [oil] >200 MW	-	10%	2.79%	13.51%	7
Steam Turbine [oil] <100 MW	-	10%	1.46%	8.33%	2
Steam Turbine [oil] <200 MW	-	10%	3.01%	12.16%	2

4. NUCLEAR UNITS

CRA assumes that nuclear plants run when available, and that they have minimum up and down times of one week. Forced outage rates for each unit are drawn from the Energy Central database of unit outages. Nuclear plants do not contribute to quick-start or spinning reserves. The model includes refueling and maintenance outages for each nuclear plant. In the near future, outages posted on the NRC website or announced in the trade press are included. For later years, refueling outages are projected on the basis of the refueling cycle, typical outage length, and last known outage dates of each plant. Since these facilities are treated as must run units, CRA does not specifically model their cost structure. Within the timeframe of this study, no nuclear retirements are applied.

5. HYDRO UNITS

GE MAPS has special provisions for modeling hydro units. For conventional or pondage units, a monthly pattern of water flow, i.e. the minimum and maximum generating capability and the total energy for each plant in each month is specified. For pumped storage units, the maximum generating & pumping capability of the plant is specified. For both types of hydro resource, CRA assumes that the plant is able to provide spinning reserves of up to 50% of plant capacity. Plant capacity data is drawn from the NERC ES&D database and the General Electric generating unit database. Plant monthly energy data is drawn from an average of Form EIA-860 submissions for 1992-1998.

6. RENEWABLE RESOURCES

It is difficult to predict exact operational patterns of wind and solar generators, since these are dependent on weather and ambient conditions. Therefore they are modeled as non-dispatchable resources with a specified annual capacity factor. Wind resources are modeled at 30% annual capacity factor, while solar generators are run at 24% annual capacity factor, and restricted to daytime hours.

7. CAPACITY ADDITIONS AND RETIREMENTS

CRA adds new generation based on projects in development or advanced stages of permitting, as indicated by trade press announcements, trade publications, environmental permit applications, and internal knowledge. CRA also adds generic capacity where economically justified, or as required to maintain resource adequacy per installed capacity reserve margins published by various ISOs and NERC regions.

Future new entry is likely to be in the form of gas-fired simple cycle (SCGT) or combined cycle (CCGT) units, depending on local needs and price patterns. In 2011, coal-fired steam turbine units may also be a viable option. Table 3 shows financing assumptions for each of these categories. The associated annual carrying cost amounts to approximately 94 $/kW-yr for CCGT units, 65 $/kW-yr for SCGT units, and 180 $/kW-yr for coal-fired units.

Table 3: New Entry Financing

Cost Component	CCGT	SCGT	ST Coal
All-In Capital Cost ($/kW)	650	400	1,500
Debt-Equity Ratio	55:45	50:50	50:50
Return on Equity	18%	18%	12%
Cost of Debt	8%	8%	8%
Term of Debt (years)	30	20	30
Fixed O&M ($/kW-yr)	20	10	25
Variable O&M ($/MWh)	2.5	5.0	1.0
Full Load Heat Rate (Btu/kWh)	6,900	10,000	9,000
Forced Outage Rate	3%	4%	4%
Planned Outage Rate	5%	5%	9%

CRA tracks planned and announced retirements from power pool load and capacity reports, as well as trade press announcements. A capacity balance for each NERC region is shown in Appendix I.

8. FUEL PRICE FORECASTS

GE-MAPS uses a monthly fuel price for each thermal unit. The fundamental assumption of behavior in competitive markets is that generators will bid their marginal cost into the energy market. The marginal cost for a gas plant is the opportunity cost of fuel purchased (in addition to non-fuel variable O&M and environmental adders), or the spot price of gas at the location closest to the plant. CRA therefore uses forecasts of spot prices at regional hubs, and refines these on the basis of historical differentials between price points and their associated hubs. For fuel oil CRA uses estimates of the price delivered to generators on a regional basis.

A number of generators can utilize a secondary fuel type. This possibility is simulated as follows:

- Natural Gas Primary: Units that primarily burn natural gas typically face stringent restrictions on the fraction of time that they may burn fuel oil. CRA makes the assumption that each unit is allowed to switch to fuel oil for the one month in each year in which the gas prices are highest.

- Fuel Oil Primary: Units that primarily burn oil may switch to gas whenever it is economically justified. However CRA assumes that natural gas shortages prevent this from happening in winter (November though March). A heat rate degradation of 3% is modeled when the unit switches to natural gas. Thus, the fuel type is switched between April and October, whenever the price of natural gas plus 3% is less than the price of fuel oil.

Coal prices are drawn from the Platts Coaldat database of January 2005, which forecasts delivered coal prices, including transportation and handling, for each major coal plant in the United States.

CRA has sent you a separate memorandum with a detailed description of natural gas and oil forecasts.

9. ENVIRONMENTAL REGULATIONS

CRA models NOx and SO_2 emission rates for all units where such data is available. In addition, CRA models compliance with various allowance trading programs, and attempts to capture the effect of future environmental regulations. All plant emission rates are drawn from the Emissions Scorecard published by the US Environmental Protection Agency. Emission rates for NOx and SO_2 are obtained from industry futures, in particular those published by the Cantor Environmental Brokerage. In this analysis CRA uses allowance trading prices based on futures for the 2008 simulations. For the 2011 simulations, CRA uses the allowance price forecast applied by the Energy Information Administration in developing the 2006 Annual Energy Outlook. CRA does not include the impacts of Carbon or Mercury emissions in these simulations.

10. EXTERNAL REGION SUPPLY

CRA explicitly models the US portion of the Eastern Interconnect, and the Canadian province of Ontario. Regions outside this study area are modeled as either supply profiles or scheduled interchanges. CRA uses historic flows, combined with expectations of future conditions in these areas to project quantities and prices of power exchanged with the model footprint. In this analysis, flows from New Brunswick to New England, and from Hydro Quebec to New England, New York, and Ontario are modeled as scheduled flows, based on 12 months of historical data.

The DC ties with the WECC and ERCOT interconnections are modeled as price sensitive supply curves. CRA uses historical electricity prices and gas prices near these DC ties to calculate market heat rates for on-peak and off-peak periods, and for summer and winter. These heat rates are multiplied by the appropriate forecast gas price in each scenario, to arrive at a price points for each DC tie. The tie is then modeled as follows:

- When the locational price at the DC tie is within ± $2.50/MWh of the corresponding price point, zero flow is assumed on the tie.
- At locational prices that are between $2.50/MWh and $7.50/MWh above the price point, the tie is modeled as importing power into the Eastern Interconnect at half its capacity.
- At locational prices that are greater than $7.50/MWh above the price point, the tie is modeled as importing power into the Eastern Interconnect at full capacity.
- At locational prices that are between $2.50/MWh and $7.50/MWh below the price point, the tie is modeled as exporting power from the Eastern Interconnect at half its capacity.
- At locational prices that are greater than $7.50/MWh below the price point, the tie is modeled as exporting power from the Eastern Interconnect at full capacity.

11. INTERRUPTIBLE LOAD

The presence of demand response is important to energy and installed capacity prices. The value of energy to interruptible loads caps the energy prices, and the capacity of interruptible load effectively replaces installed reserves and lowers the capacity value. CRA uses values for interruptible load, and demand side management reduction in peak, as reported by the various Independent System Operators and reliability regions in the EIA-411 and other equivalent annual forecasts. This dispatchable demand is spread among load areas based on their load share of the total system load (unless there is more detailed data available). The dispatchable demand is implemented as generators with a dispatch price of $600/MWh for the first block (50% of area dispatchable demand) and $800/Mwh for the second block. These units rarely run, as the high prices they require indicate a supply shortfall and prompt economic new entry. Thus dispatchable demand plays an insignificant direct role in the energy market.

12. MARKET MODEL ASSUMPTIONS

A. **Marginal Cost Bidding:** All generation units are assumed to bid marginal cost (opportunity cost of fuel plus non-fuel VOM plus opportunity cost of tradable permits). It is reasonable to assume that the real markets are not perfectly competitive and thus the model tends to underestimate the prices in the real markets.

B. **Installed Capacity:** Installed capacity reserve requirements are set at a percentage of forecast peak load for each NERC region or sub-region, as shown in Table 4. CRA adds capacity to ensure that each region meets the installed capacity target indicated by these requirements.

Table 4: Installed Capacity (% of Peak Load)

Pool	Fraction
NEPOOL	115%
NYPP	118%
Long Island	99%
New York City	80%
MAAC	116%
ECAR	115%
MAIN	117%
MAPP	115%
SPP	115%
Entergy	115%
Southern	115%
TVA	115%
VACAR	115%
FRCC	118%
Ontario	118%

C. **ISO Boundaries:** CRA uses hurdle rates for all flows (transactions) between various ISOs. These hurdle rates simulate both existing wheeling rates and market inefficiencies associated with inter-ISO transactions. All hurdle rates are set at $2/MWh in each direction in both commitment and dispatch, except as documented in Table 5.

Table 5: Hurdle Rates ($/MWh Flow)

From	To	Commitment	Dispatch
ISO-NE	NYISO	$6	$4
NYISO	ISO-NE	$8	$6
PJM	NYISO	$4	$1
NYISO	PJM	$6	$6
ONTARIO	NYISO	$3	$1
NYISO	ONTARIO	$6	$3
PJM	MISO	$0	$0
MISO	PJM	$0	$0

D. **Operating Reserves:** Operating reserves are based on requirements instituted by each reliability region. These requirements are based on the loss of the largest single generator, or the largest single generator and half the second largest generator, or a percentage of peak demand. The spinning reserves market affects energy prices, since units that spin cannot produce electricity under normal conditions. Energy prices are higher when reserves markets are modeled. Table 6 shows a list of operating reserves by reliability region, and the fraction met by spinning reserves. The remainder is assumed to be met by quick start reserves.

Table 6: Operating Reserve Requirements

ISO/Region	Operating Reserve	% Met by Spin
ISO-NE	1,900 MW	67%
NYISO	1,200 MW	50%
Eastern NY	1,200 MW	25%
Long Island	120 MW	50%
PJM	4,500 MW	67%
Midwest ISO	4% of load	65%
MAPP	871 MW	65%
SPP	1,746 MW	65%
Entergy	4% of load	65%
Southern	4% of load	65%
TVA	4% of load	65%
VACAR	4% of load	65%
FRCC	853 MW	65%
Ontario	1,600 MW	55%

E. **Marginal transmission Losses:** GE MAPS has the capability of simulating marginal losses and their impact on locational energy prices. However these analyses do not include marginal losses in any calculations.

APPENDIX I: CAPACITY BALANCE

ISO-NE	2006	2007	2008	2009	2010	2011
Forecast Peak (MW)	28,583	29,016	29,449	29,850	30,230	30,624
Interruptible Load (MW)	1,485	1,534	1,566	1,571	1,534	1,450
Net Demand (MW)	27,098	27,482	27,883	28,279	28,696	29,174
Reserve Margin (%)	15	15	15	15	15	15
Load + Reserve (MW)	31,163	31,604	32,065	32,521	33,000	33,550
Firm Transfers (MW)	463	463	463	463	456	456
Installed Capacity (MW)	31,267	30,917	31,433	31,433	31,433	32,933
Capacity Surplus (MW)	567	-224	-169	-625	-1,111	-161
NYISO	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Forecast Peak (MW)	15,739	15,913	16,061	16,243	16,430	16,632
Interruptible Load (MW)	137	137	137	142	142	147
Net Demand (MW)	15,602	15,776	15,924	16,101	16,288	16,485
Reserve Margin (%)	18	18	18	18	18	18
Load + Reserve (MW)	18,410	18,616	18,790	18,999	19,220	19,452
Firm Transfers (MW)	-225	-225	-305	-305	-298	-298
Installed Capacity (MW)	24,058	23,735	23,247	23,247	23,247	23,247
Capacity Surplus (MW)	5,423	4,894	4,152	3,943	3,729	3,497
New York City	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Forecast Peak (MW)	11,505	11,660	11,805	11,965	12,090	12,217
Interruptible Load (MW)	71	71	71	74	74	76
Net Demand (MW)	11,434	11,589	11,734	11,891	12,016	12,141
Reserve Margin (%)	-20	-20	-20	-20	-20	-20
Load + Reserve (MW)	9,147	9,271	9,387	9,513	9,613	9,713
Firm Transfers (MW)	0	0	0	0	0	0
Installed Capacity (MW)	10,325	10,550	9,695	9,695	9,530	10,030
Capacity Surplus (MW)	1,178	1,279	308	182	-83	317
Long Island	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Forecast Peak (MW)	5,320	5,410	5,500	5,580	5,680	5,779
Interruptible Load (MW)	71	71	71	74	74	76
Net Demand (MW)	5,249	5,339	5,429	5,506	5,606	5,703
Reserve Margin (%)	-1	-1	-1	-1	-1	-1
Load + Reserve (MW)	5,197	5,286	5,375	5,451	5,550	5,646
Firm Transfers (MW)	0	0	0	0	0	0
Installed Capacity (MW)	5,175	5,175	5,405	5,405	5,405	5,655
Capacity Surplus (MW)	-22	-111	30	-46	-145	9

MAAC	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Forecast Peak (MW)	58,784	59,909	61,025	62,136	63,244	64,368
Interruptible Load (MW)	803	793	793	793	793	793
Net Demand (MW)	57,981	59,116	60,232	61,343	62,451	63,575
Reserve Margin (%)	16	16	16	16	16	16
Load + Reserve (MW)	67,258	68,575	69,869	71,158	72,443	73,747
Firm Transfers (MW)	0	0	0	0	0	0
Installed Capacity (MW)	69,249	68,801	69,591	69,591	69,591	73,591
Capacity Surplus (MW)	1,991	226	-278	-1,567	-2,852	-156
ECAR	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Forecast Peak (MW)	106,753	108,749	110,942	112,867	114,598	116,432
Interruptible Load (MW)	2,523	2,499	2,519	2,520	2,475	2,395
Net Demand (MW)	104,230	106,250	108,423	110,347	112,123	114,037
Reserve Margin (%)	15	15	15	15	15	15
Load + Reserve (MW)	119,865	122,188	124,686	126,899	128,941	131,143
Firm Transfers (MW)	0	0	0	0	0	0
Installed Capacity (MW)	128,202	129,835	130,593	130,871	130,871	132,411
Capacity Surplus (MW)	8,338	7,648	5,907	3,972	1,930	1,268
MAIN	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Forecast Peak (MW)	60,184	61,518	62,608	63,645	64,641	65,644
Interruptible Load (MW)	3,453	3,466	3,471	3,476	3,479	3,483
Net Demand (MW)	56,731	58,052	59,137	60,169	61,162	62,161
Reserve Margin (%)	17	17	17	17	17	17
Load + Reserve (MW)	66,375	67,921	69,190	70,398	71,560	72,728
Firm Transfers (MW)	-61	-69	-141	-143	-54	-56
Installed Capacity (MW)	68,486	68,546	69,506	70,973	72,364	72,614
Capacity Surplus (MW)	2,050	556	175	432	750	-170
MAPP	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Forecast Peak (MW)	30,712	31,288	31,939	32,492	33,070	33,722
Interruptible Load (MW)	270	271	272	273	274	275
Net Demand (MW)	30,442	31,017	31,667	32,219	32,796	33,447
Reserve Margin (%)	15	15	15	15	15	15
Load + Reserve (MW)	35,008	35,670	36,417	37,052	37,715	38,464
Firm Transfers (MW)	1,151	1,132	1,203	1,198	1,210	1,222
Installed Capacity (MW)	34,309	34,592	36,352	37,043	37,043	37,643
Capacity Surplus (MW)	452	54	1,138	1,189	538	401

SPP	2006	2007	2008	2009	2010	2011
Forecast Peak (MW)	42,196	42,893	43,465	44,312	45,274	45,579
Interruptible Load (MW)	934	943	967	1,007	1,004	1,005
Net Demand (MW)	41,262	41,950	42,498	43,305	44,270	44,574
Reserve Margin (%)	15	15	15	15	15	15
Load + Reserve (MW)	47,451	48,243	48,873	49,801	50,911	51,260
Firm Transfers (MW)	450	485	442	319	49	-40
Installed Capacity (MW)	56,183	56,183	56,183	56,183	57,033	57,033
Capacity Surplus (MW)	9,182	8,426	7,752	6,701	6,172	5,733
Entergy	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Forecast Peak (MW)	28,360	28,858	29,422	29,654	30,090	30,742
Interruptible Load (MW)	465	460	469	472	464	471
Net Demand (MW)	27,895	28,398	28,953	29,182	29,626	30,271
Reserve Margin (%)	15	15	15	15	15	15
Load + Reserve (MW)	32,079	32,658	33,296	33,559	34,070	34,812
Firm Transfers (MW)	0	0	0	0	0	0
Installed Capacity (MW)	46,467	47,066	47,866	47,866	47,866	47,866
Capacity Surplus (MW)	14,388	14,408	14,570	14,307	13,796	13,054
Southern	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Forecast Peak (MW)	48,312	49,629	50,857	52,066	53,240	54,448
Interruptible Load (MW)	138	138	138	138	138	138
Net Demand (MW)	48,174	49,491	50,719	51,928	53,102	54,310
Reserve Margin (%)	15	15	15	15	15	15
Load + Reserve (MW)	55,400	56,915	58,327	59,717	61,067	62,457
Firm Transfers (MW)	0	0	0	0	0	0
Installed Capacity (MW)	65,102	65,105	65,105	65,105	65,105	65,105
Capacity Surplus (MW)	9,702	8,190	6,778	5,388	4,038	2,649
TVA	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Forecast Peak (MW)	31,757	32,411	32,848	33,641	34,176	35,035
Interruptible Load (MW)	2,155	1,987	1,981	1,992	2,002	2,013
Net Demand (MW)	29,602	30,424	30,867	31,649	32,174	33,022
Reserve Margin (%)	15	15	15	15	15	15
Load + Reserve (MW)	34,042	34,988	35,497	36,396	37,000	37,975
Firm Transfers (MW)	0	0	0	0	0	0
Installed Capacity (MW)	36,901	38,151	38,151	38,151	38,151	38,151
Capacity Surplus (MW)	2,859	3,163	2,654	1,755	1,151	176

VACAR	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Forecast Peak (MW)	61,224	62,512	63,735	64,944	66,141	67,402
Interruptible Load (MW)	2,228	2,223	2,216	2,208	2,199	2,190
Net Demand (MW)	58,996	60,289	61,519	62,736	63,942	65,212
Reserve Margin (%)	15	15	15	15	15	15
Load + Reserve (MW)	67,845	69,332	70,747	72,146	73,533	74,994
Firm Transfers (MW)	0	0	0	0	0	0
Installed Capacity (MW)	68,659	69,105	70,620	70,354	70,354	74,854
Capacity Surplus (MW)	814	-227	-127	-1,792	-3,179	-140
FRCC	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Forecast Peak (MW)	47,994	49,139	50,414	51,700	53,030	54,370
Interruptible Load (MW)	3,386	3,381	3,386	3,384	3,405	3,425
Net Demand (MW)	44,608	45,758	47,028	48,316	49,625	50,945
Reserve Margin (%)	18	18	18	18	18	18
Load + Reserve (MW)	52,637	53,994	55,493	57,013	58,558	60,115
Firm Transfers (MW)	1,752	1,752	1,752	1,752	1,555	1,555
Installed Capacity (MW)	50,127	51,893	53,619	53,619	57,619	58,469
Capacity Surplus (MW)	-758	-349	-122	-1,642	617	-91